Alberta
ENERGY

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09-10

GAS ROYALTY CALCULATION INFORMATION BULLETIN October 2009

A. PRICING RATES AND TRANSPORTATION INFORMATION
Pricing, Royalty Rates and Transportation Information – August 2009 2

B. NOTICES
Operating Costs Subject to Recapture 2

C. MONTHLY INFORMATION
August 2009 Royalty Due November 30 2
September 2009 VA4 Due November 15 3
Registry Deadline Submissions 3
Interest Rate October 2009 3
July Provisional Assessment Charge 3
July Penalty Charges 3
Gas Royalty Calculation Support 4
Well Event Measured Depth Determination Letter 4

D. INFRASTRUCTURE DATA CHANGES
Client ID Listing 4
Client Status Changes 5
Nova Tolls – Multiple Gas Reference Prices 5

E. REMINDERS
Statutory Requirement and Recalculation of 2005 Royalty 5
Incorporating Greenhouse Gas (GHG) Emission Compliance Costs into the Natural Gas Royalty Regime 6

F. POINTS OF CONTACT
Petroleum Registry of Alberta 8
Alberta Energy internet 8
Gas Royalty Client Services 8
Reference Prices and Valuation Allowances Calculation Information 9

PLEASE ENSURE YOUR PRODUCTION ACCOUNTANTS RECEIVE A COPY OF THIS DOCUMENT.

A. PRICING RATES AND TRANSPORTATION INFORMATION

For Pricing, Royalty Rates and Transportation Information for August 2009, refer to Attachments 1, 1A, 2, 2A and 3. These attachments are also available in Excel Format.

B. NOTICES

Operating Costs Subject to Recapture

The Potential Operating Cost Recapture report for the 2008 production year was issued in the June 2009 calendar month and continues to be issued monthly with the invoice. Operating costs are recaptured from a royalty client who has volumes at a facility where they have no capital ownership (as identified on the AC1, AC2 or AC3 submission) and no reported custom processing fees (AC5). A royalty client who is not an owner at a facility, and does not pay custom processing fees, is not entitled to the operating costs they received on a monthly basis. The operating costs subject to recapture will be charged in the August 2009 billing period invoice issued in October 2009.

C. MONTHLY INFORMATION

August 2009 Royalty Due November 30

- **Royalty clients are to remit the total amount payable shown on the November 2009 Statement of Account by November 30, 2009.** If the amount payable includes accrued current period interest, the interest has only been accrued to the statement issue date. Clients must also include the additional interest that has accrued from the statement issue date to the date of payment, using the per diem amount provided.

- **The November 2009 Statement of Account shows your amount payable as of the Statement issue date. It includes any outstanding balances from your previous statement, your August 2009 invoice amount and any applicable current period interest charges. It also identifies refunds resulting from overpayments.**

- Current period interest will not be charged on current invoice charges for the production month of August 2009 if it is paid in full by November 30, 2009.

- Current period interest will accrue on any overdue charges commencing the first day after the due-date until it is paid in full.

  Note: If the due date falls on a non-business day, the next business day will apply as the due date.

- Cheques are payable to the Minister of Finance, Province of Alberta.

September 2009 VA4 Due November 15

The VA4 forms for the production month of September 2009 are due in the department offices by November 15, 2009.

Note: If the due date falls on a non-business day, the next business day will apply as the due date for VA4 forms.

Registry Deadline Submissions

The Registry deadline submissions for SAF, OAF, and Volumetrics are posted in the Petroleum Registry of Alberta website "Reporting Calendars" under Bulletin Board.

Changes to this calendar will be posted on the Registry website home page in "Broadcast Messages."

Interest Rate October 2009

Alberta Energy's interest rate for October 2009 is 3.25%.

July Provisional Assessment Charge

The summary of Provisional Assessment Charges for all production periods in the July 2009 billing period was:

First Time Provisional Assessment	Reversals of Provisional Assessments	Net Provisional Assessment
$3,396,916.99	($2,068,468.43)	($1,328,448.56)

July Penalty Charges

The penalty table below shows at the form level, the total penalty charges and reversals, for the July 2009 billing period:

FORM	Penalty Charges	Penalty Reversals	Net Penalty Charges for 2009/07
AC2	$26,400	$400	$26,000
AC4	$3,200	$200	$3,000
AC5	$2,900	$0	$2,900
NGL1	$0	$0	$0
VA2	$0	$0	$0
VA3	$0	$0	$0
VA4	$900	$0	$900
Total	$33,400	$600	$32,800

Gas Royalty Calculation Support

Upon request, Gas Royalty Calculation staff will be available to meet with clients who need assistance with royalty reporting. Royalty clients requiring assistance are encouraged to contact your respective Gas Royalty Client Services portfolio representative, as identified in Section F of this bulletin, to arrange a meeting.

Well Event Measured Depth Determination Letter

The department has issued a "Well Event Measured Depth Determination Letter" under the Report Package DOE – Gas to facility operators via the PRA on October 1 and 13, 2009. This letter shows the confirmed Measured Depth (MD) of each active well event that will be used to calculate The Depth Factor (DF) of the quantity component rate under the new royalty formula. A well event that is not listed on the letter and does not have a confirmed MD will receive a DF of 1. When the changes to the MD are confirmed by the department, a letter is issued to a facility operator who reports changes through the PRA to well event attributes affecting MD. All changes to the MD are applied on a go forward basis only, if a retroactive change is required, a written request must be submitted to the department. Facility operators are advised to submit well event attribute changes by the last day of the calendar month in order for timely determination of MD.

D. INFRASTRUCTURE DATA CHANGES

Client ID Listing

The BA Identifiers Report is a directory of Business Associate (BA) names, codes, status (e.g. struck, active, amalgamated, etc.), status effective dates, and effective August 2004, includes Working Interest Owner (WIO) role start/end dates.

This report is also published daily on the Petroleum Registry website at:

http://www.petroleumregistry.gov.ab.ca

The department reminds Business Associates to review their WIO role to ensure that the start and end dates are reflected correctly. If the BA does not have an active WIO role, the operators cannot allocate volumes to the BA for the relevant production periods through the SAF/OAF allocations.

- If a BA has a WIO role, then that BA can receive SAF/OAF allocations from the WIO role start date forward.
- If a BA has a WIO role with an end date, then they can only receive SAF/OAF allocations from the WIO role start date until the end date. Any SAF/OAF allocations after the end date will be rejected.
- If a BA does not have a WIO role start date, then that BA cannot receive SAF/OAF allocations.

Please contact Client Registry at 780-422-1395 if you have any questions regarding the information supplied on this listing.

Client Status Changes

Clients must ensure that all royalty documents are completed using only valid client names and IDs. It is critical that royalty clients use current legal client names and their appropriate IDs on all documents to ensure accurate royalty calculation and to prevent provisional assessment and penalties. Rejects will occur when invalid IDs are used.

If you require information regarding client names or IDs, please contact Client Registry at 780-422-1395.

Nova Tolls - Multiple Gas Reference Prices

Royalty information related to the implementation of the Factor Model negotiated with industry for determining Multiple Gas Valuation Prices is provided on the Natural Gas website's Royalty Related Information page under Facility Royalty Trigger Factors and Meter Station Ties.

E. REMINDERS

Statutory Requirement and Recalculation of 2005 Royalty

A production year becomes statute barred on December 31st, four years after the end of a production year. Once a year has become statute barred, calculation or recalculation of royalty does not occur on a monthly basis. Section 38 of the Mines and Minerals Act provides for recalculation of royalty that can be initiated in two ways:

1. On the department's initiative in conjunction with an audit or examination; or
2. At the request of a royalty payer.

Audits in Progress

Non-operator partners are advised that certain 2005 allowable costs, custom processing fees, capital costs and custom processing adjustment factor (CPAF), and reporting discrepancy audits are currently in progress. It is anticipated that these audits may be completed before December 31, 2009. However, should circumstances require that these audits be completed in 2010, a list of the affected ERCB facilities will be included in the December 2009 Information Bulletin. Royalty clients are also reminded that amendments received by the department in the fourth year following the production year may be subject to audit. If the amendments are received late in the fourth year and insufficient time is available for the department to commence a review of the amendments prior to the end of the year, the department reserves the right to commence the audit at the beginning of the fifth year.

If you have any questions, please contact Kris Pretty of the Compliance & Assurance group at (403) 297-8785.

Industry Recalculation of 2005 Royalty

Industry initiated royalty recalculation requests for the 2005 production year must be submitted in writing to the attention of Wayne Taljit, Manager of Gas Royalty Client Services. This request must be received by the department on, or before, December 31, 2009 and it must include the following:

- Identification of the recalculation facility or facilities;
- The reason for the recalculation;
- An order of magnitude estimate, i.e. the approximate amount of the royalty impact;
- Identification of the royalty clients that may be impacted by the request;
- The time lines for recalculation preparation and submission to the Crown including a reasonable time for the Crown to review the submission; and
- Confirmation that the affected partner(s) have been notified.

If you have any questions regarding this process please contact your Gas Royalty Client Services portfolio representative as identified in Section F of this bulletin.

Incorporating Greenhouse Gas (GHG) Emission Compliance Costs into Natural Gas Royalty Regime

As announced in the Information Letter 2009-25, Alberta Environment introduced the Specified Gas Emitters Regulation (SGER) in July 2007, to meet compliance requirements for the reduction of greenhouse gas emissions. The SGER provides industry with the following options to meet compliance requirements:

- Implementing capital projects or improving facility operations
- Purchasing emission offsets
- Purchasing or selling performance debits/credits
- Purchasing Climate Change & Emissions Management Fund (the Fund) credits.

Effective July 1, 2007, the department will recognize capital costs, operating costs, and custom processing fees resulting from compliance with the SGER, provided the costs are incurred and paid in Alberta, as allowable costs for Crown royalty purposes. The Crown will recognize the costs incurred from purchasing Alberta based emission offsets, performance debits/credits and the Fund credits as allowable costs. The Crown will also share proportionately in any revenue earned from the sale of performance credits. Any penalties levied for non-compliance under Section 28 of Alberta Environment's SGER are not deemed as allowable costs.

As the breakdown in custom processing and capital costs is not always transparent, or it may be difficult for royalty clients to identify costs associated with GHG emission compliance costs, these costs may not be distinguished in the reporting of capital cost and custom processing fee allowances. Facility operators/designated royalty clients may have already claimed these costs, but if not, cost forms should be amended to include costs where necessary.

A breakdown in the reporting of operating costs is required. The operators must identify the operating costs associated with GHG emission compliance costs for Crown royalty purposes.

The royalty treatment of GHG emission compliance costs will be similar to other allowable costs:

- Deducted only by way of reductions from royalty compensation owing to the Crown for natural gas and gas products royalty
- May not exceed the total royalty compensation otherwise owed to the Crown for natural gas and gas products royalty for that year
- Allowable costs, which are not recovered in that year, may not be carried forward to a subsequent year
- Subject to audit

Reporting of Operating Costs for Production Years 2007 and 2008
(Reporting for periods covered by Natural Gas Royalty Regulation, 2002)

The current Allowable Operating Cost form for Production Year 2004 and Onwards (AC4-V2) does not allow a client to report GHG emission compliance costs separately from other allowable operating costs. In an effort to minimize system and form enhancements, the operating costs associated with purchasing emission offsets, performance debits/credits, or the Fund credits, are not to be reported on the AC4-V2 for production years 2007 and 2008.

In order to claim these operating costs, the operator of an ERCB facility required under the SGER to reduce GHG emissions, or the operator of an ERCB facility that has sold a performance credit to a facility to assist in compliance obligations, must submit a letter to the department, with supporting documentation. GHG emission compliance costs are to be claimed at an ERCB facility level. If applicable, facility operators must include the percentage of operating costs that is to be allocated to each working interest owner or designated royalty client.

Requests should be forwarded to the following address, before a production year becomes statute barred.

Attention: Wayne Taljit, Manager, Client Services
Gas Royalty Calculation
8th Floor NPP
9945-108 Street
Edmonton, AB T5K 2G6

Once the department has completed its review, an amendment will be processed. It will be reflected as a Financial and Volumetric adjustment on the facility operator's invoice. It is the operator's responsibility to allocate the credit amongst the working interest owners. An allowable cost restriction will apply if the Crown share of allowable cost deduction exceeds the total royalty compensation owed to the Crown by the royalty client. This restriction will be manually applied at the Working Interest Owner level. The department will monitor this adjustment until the production year becomes statute barred.

Reporting of Operating Costs effective Production Year 2009
(Reporting for periods covered by Natural Gas Royalty Regulation, 2009)

A separate line item will be included on the Capital and Operating Cost Allowance form (AC2-V4) to capture GHG emission compliance costs. These costs should be reported separately from the other allowable operating costs as they are not subject to overhead and working capital.

F. POINTS OF CONTACT

Petroleum Registry of Alberta

The Petroleum Registry of Alberta Service Desk is the focal point for communications with the Registry regarding preparations for, access to, or utilization of the Registry. To contact the

Petroleum Registry of Alberta Service Desk call: 1-800-992-1144.

Alberta Energy Internet

Prices, Royalty Rates and Transportation Information are available on the Alberta Energy Internet address: www.energy.alberta.ca, from "Our Business", navigate to "Natural Gas", "About Natural Gas", "Prices", "Alberta Natural Gas Reference Price (ARP)".

In addition, both the Gas Royalty Information Bulletins and Information Letters are also available under "Our Business", navigate to "Natural Gas", "Legislation, Guidelines & Policies".

Gas Royalty Client Services

Gas Royalty Client Services is structured as a Business Associate client portfolio system, which assigns a given Business Associate to one of four Client Services teams. Listed below is the portfolio breakdown along with Client Services Team Leads and phone numbers. The portfolios are divided by company name and not by BA ID.

Example: If your company name is the "Gas Company" you would call C – G team at 780-644-1202.

Numbered companies, A, B & L	780-644-1201 GRCST1@gov.ab.ca	Todd Atwood
C – G	780-644-1202 GRCST2@gov.ab.ca	Lily Hiew
H – P (excluding L)	780-644-1203 GRCST3@gov.ab.ca	Chris Nixon
Q – Z	780-644-1204 GRCST4@gov.ab.ca	Jyoti Bhambhani

Gas Royalty Reception: 780-422-8727
Fax: 780-427-3334 or 780-422-8732
Alberta Toll Free: 780-310-0000

Hours of operation are 8:15 a.m. to 4:30 p.m. Voice messages left after 4:30 p.m. will be answered the next business day.

In situations where a company has just amalgamated or purchased another company, the general rule is to call the team that is responsible for the "Supra" business associate, or Royalty payer. Below are some guidelines for clients who are unsure which Client Services Team to call regarding their questions.

1. **Amalgamation/consolidation** - Call the team responsible for the "Supra" business associate (Royalty Payer).
   i.e. ABC Oil and Gas amalgamates with Zed Exploration and Zed is the amalgamator (royalty payer). When calling Client Services regarding business for ABC Oil and Gas, you would call Team 4 (Q-Z) (780-644-1204) because Zed Exploration is now the Supra business associate and royalty payer. This rule would apply even if you were calling regarding business that is prior to the acquisition or amalgamation.

2. **Asset Purchase** - Call the team responsible for your company.
   i.e. 123 Gas purchases the assets of TSP Exploration, but not the company. When calling Client Services regarding business for 123 Gas, you would call Team 1 (# Co., A, B, & L) (780-644-1201) because you have only purchased assets.

3. **Consultants/service providers** - If you have a contract to provide production accounting services to a company, call the team responsible for your client's company.
   i.e. Paul Snow Consulting Services enters into a contract with Duckback Oil and Gas and Olive Oil and Gas. Paul Snow would contact Team 2 (C-G) (780-644-1202) to discuss Duckback Oil business and Team 3 (H-P excluding L) (780-644-1203) to discuss Olive Oil and Gas business. At the time the contract is signed, Paul Snow would have had each company notify the appropriate team that he was authorized to access information for their company.

Reference Prices and Valuation Allowances Calculation Information

Gas Royalty Valuation and Markets
300, 801 – 6 Avenue SW
Calgary, Alberta T2P 3W2
Telephone: 403-297-5514
Fax: 403-297-5400

Deen Khan
Director, Gas Royalty Calculation
Royalty Operations – Edmonton

Attachments

2009 GAS AND ISC PRICES

MONTH	Gas Reference Price ($/GJ)	Methane ISC Reference Price ($/GJ)	Methane ISC Par Price ($/GJ)	Ethane ISC Reference Price ($/GJ)	Propane ISC Reference Price ($/GJ)	Butane ISC Reference Price ($/GJ)	Pentanes plus ISC Reference Price ($/GJ)
JAN	5.77	5.74	5.74	6.15	6.27	6.29	6.31
FEB	4.66	4.61	4.61	5.12	5.30	5.33	5.35
MAR	4.01	3.97	3.97	4.53	4.71	4.72	4.75
APR	3.41	3.35	3.35	3.88	4.09	4.12	4.14
MAY	3.13	3.10	3.10	3.42	3.53	3.56	3.58
JUN	2.97	2.94	2.94	3.30	3.42	3.44	3.46
JUL	2.94	2.92	2.92	3.18	3.24	3.27	3.30
AUG	2.72	2.70	2.70	2.83	2.85	2.88	2.91
SEPT							
OCT							
NOV							
DEC							

2008 Weighted Average Gas Reference Price ($/GJ)
7.412

2008 Weighted Average OMAC ($/GJ)
0.019

DETAIL OF THE AUGUST 2009 GAS AND ISC REFERENCE PRICES						
	Gas	Methane	C2-IC	C3-IC	C4-IC	C5-IC
Weighted Average Price of Alberta	2.966	2.964	3.016	2.997	3.001	3.012
Deductions: Intra – Alberta Transportation	0.266	0.283	0.161	0.113	0.088	0.067
Marketing Allowance	0.011	0.011	0.011	0.011	0.011	0.011
Price Before Pipeline Factor	2.689	2.670	2.844	2.873	2.902	2.934
Pipeline Fuel/Loss Factor	0.993	0.993	0.993	0.993	0.993	0.993
Price before Special Adjustment	2.670	2.651	2.824	2.853	2.882	2.913
Special Adjustment	0.000	0.000	0.000	0.000	0.000	0.000
Price before 2% amendment limitation or rounding	2.670	2.651	2.824	2.853	2.882	2.913
Amendments: Carry forward (from previous RP month)	0.072	0.077	0.012	0.005	-0.001	-0.001
Prior Period Amendment Adjustment (current RP month)	-0.004	-0.003	-0.003	-0.003	-0.003	-0.003
Calculated RP after Amendments	2.738	2.725	2.833	2.855	2.878	2.909
August 2009 Reference Price	**2.72**	**2.70**	**2.83**	**2.85**	**2.88**	**2.91**
Difference = value carried forward to next RP month	0.018	0.025	0.003	0.005	-0.003	-0.001
Adjusted IATD (before Prior Period Amendments)	n/a	0.281	0.160	0.113	0.087	0.066
Prior period Amendments (IATD and Pipeline Fuel Loss)	n/a	0.000	0.000	0.000	0.000	0.000
Adjusted IATD (after Prior Period Amendments)	n/a	0.281	0.160	0.113	0.087	0.066

2009

NATURAL GAS LIQUIDS PRICES

MONTH	Ethane Reference Price ($/GJ)	Ethane Par Price ($/GJ)	Propane Reference Price ($/m3)	Propane Floor Price ($/m3)	Butane Reference Price ($/m3)	Butane Floor Price ($/m3)	Pentanes plus Reference Price ($/m3)	Pentanes plus Par Price ($/m3)	Sulphur Default Price ($ per tonne)
JAN	6.15	6.15	230.29	209.33	310.61	206.67	348.86	325.57	21.41
FEB	5.12	5.12	258.66	188.18	277.46	185.58	332.24	304.31	9.42
MAR	4.53	4.53	191.60	170.24	311.71	180.47	405.64	380.07	35.33
APR	3.88	3.88	171.72	169.45	298.88	176.85	399.85	370.33	28.70
MAY	3.42	3.42	168.58	167.74	297.93	187.74	423.40	391.47	25.58
JUN	3.30	3.30	201.00	191.86	357.43	242.85	470.29	450.47	12.82
JUL	3.18	3.18	152.83	152.98	332.74	236.33	439.05	415.03	42.08
AUG	2.83	2.83	160.85	148.14	394.72	228.96	468.90	452.65	1.37
SEPT									
OCT									
NOV									
DEC									

ANNUAL SULPHUR DEFAULT PRICE

2004	2005	2006	2007	2008
31.88	33.98	18.82	32.82	$296.50

2009

NGL TRANSPORTATION ALLOWANCE AND DEDUCTIONS

MONTH	PENTANES PLUS (a)				PROPANE AND BUTANE (b)				PENTANES PLUS, PROPANE & BUTANE (c)				FRAC. ALLOW.
	REGION				REGION				REGION				
	1	2	3	4	1	2	3	4	1	2	3	4	(per m3)
JAN	27.97	10.55	36.88	18.00	39.25	25.79	33.99	-3.31	40.23	45.50	43.56	29.53	17.25
FEB	25.80	30.88	42.93	25.11	27.25	12.51	21.86	-11.81	46.71	47.25	67.48	33.91	17.25
MAR	26.82	21.32	38.98	22.16	37.54	27.84	31.17	-40.67	58.25	52.01	64.22	45.99	17.25
APR	28.19	26.90	45.36	29.98	42.87	25.56	35.55	8.19	55.88	50.16	60.38	42.39	17.25
MAY	29.40	28.03	63.30	29.70	33.17	20.09	88.53	46.06	46.67	43.29	56.38	34.81	17.25
JUN	14.94	23.55	36.40	25.25	40.56	35.36	38.57	60.65	61.31	51.83	60.30	49.21	17.25
JUL	19.35	27.85	33.44	30.23	34.85	30.12	61.31	37.87	53.14	45.30	50.11	40.98	17.25
AUG	12.81	17.64	23.69	25.77	32.48	31.94	7.94	18.41	68.26	64.12	68.87	55.76	17.25
SEPT													
OCT													
NOV													
DEC													

(a) Pentanes Plus obtained as a specification gas product,
(b) Propane and Butane obtained as specification products, and
(c) Pentanes Plus, Propane and Butane contained in a natural gas liquids mix.

Note: For details on "Prior Period Amendment Effects", see Attachment 2A.

PRIOR PERIOD AMENDMENT EFFECTS			
NGL REFERENCE PRICES	August 2009		
	Propane	*Butanes*	*Pentanes*
Price before amendments	160.850465	394.416175	470.838101
Opening Rollover (from prior business mth)	0.000779	-0.003703	-0.002709
Prior Period Amendment Adj. (NGL-100)	0.000000	0.309364	-1.935851
Published Reference Price	**160.85**	**394.72**	**468.90**

TRANSPORTATION ALLOWANCES	August 2009											
	Pentanes Plus				Propane and Butane				Pentanes Plus, Propane & Butane			
AMENDMENTS	Region 1	Region 2	Region 3	Region 4	Region 1	Region 2	Region 3	Region 4	Region 1	Region 2	Region 3	Region 4
Opening Rollover (from prior business mth)	0.003804	-0.002115	0.000914	-0.001806	-0.002796	0.003927	-0.004784	-0.001166	-0.001088	0.000691	0.002106	-0.001193
Prior Period Amendment Adj. (NGL-100)	-1.935851	-1.935851	-1.935851	0.424741	-11.622019	0.098795	-30.972230	-0.422066	-3.487841	0.480707	-2.509615	-0.303562
Total Amendment Effect	-1.932047	-1.937966	-1.934937	0.422935	-11.624815	0.102722	-30.977014	-0.423232	-3.488929	0.481398	-2.507509	-0.304755
Calculated Transp. Differential	14.742201	19.579467	25.622601	25.348311	44.104342	31.842142	38.914191	18.834065	71.745258	63.633729	71.382295	56.067331
Calculated Transp. Differential after Total Amendments	12.810154	17.641501	23.687664	25.771246	32.479527	31.944864	7.937177	18.410833	68.256329	64.115127	68.874786	55.762576
Published Transportation Allowance	**12.81**	**17.64**	**23.69**	**25.77**	**32.48**	**31.94**	**7.94**	**18.41**	**68.26**	**64.12**	**68.87**	**55.76**

Effective the January 2009 production period, the royalty rates for **methane** and **ethane** will be calculated based on a new royalty formula. The new royalty formula consists of the sum of a price component and a quantity component. The new royalty rates will range from 5% to 50%. **Propane** and **butanes** will have fixed royalty rates of 30%, whereas **pentanes plus** will have a fixed royalty rate of 40%.

The price component of the new royalty formula royalty rate for methane and ethane is determined by the monthly methane or ethane par price (PP)

Price ($/GJ)	r_p
PP ≤ 7.00	(PP – 4.50) * 0.0450
7.00 < PP ≤ 11.00	(PP – 7.00) * 0.0300 + 0.1125
PP > 11.00	(PP – 11.00) * 0.0100 + 0.2325
Maximum	30%
Minimum	Can be negative (-20.25% if PP=0)

The par price is a provincial weighted price determined by the department and published in the Information Letter for each production month. Determination of the par price has not changed under the Alberta Royalty Framework.

The quantity component of the new royalty formula royalty rate for methane and ethane is based on the average daily production (ADP) of the well event. The quantity component is adjusted for either the depth of the well event and/or the acid gas content of the well event.

Quantity ($10^3m^3/d$)	r_q
ADP≤ (6 * DF)	[ADP – (4 * DF)] * (0.0500/DF)
(6 * DF) < ADP ≤ (11* DF)	[ADP – (6 * DF)] * (0.0300/DF) + 0.1000
ADP > (11* DF)	[ADP – (11 * DF)] * (0.0100/DF) + 0.2500
Maximum	30%
Minimum	Can be negative

The ADP for a well event is the total raw gas production in thousand cubic metres (10^3m^3) for the month divided by the total hours of production in that month multiplied by 24. The ADP formula is as follows:

$$\text{ADP} = \frac{\text{total raw gas production}}{\text{total hours of production}} \times 24$$

Acid Gas Factor (AGF) is a factor that adjusts the ADP of a well event if that well event is producing high amounts of acid gas, that is, if the combined concentration of hydrogen sulphide (H2S) and carbon dioxide (CO_2) is greater than 3% and less than or equal to 25%. If a well event has an acid gas content of less than or equal to 3%, then the AGF of the well event will default to 1.00. If a well event has acid gas content greater than 25% then the AGF has a minimum value of 0.78.

The AGF is determined based on the following formula:

$$AGF = [1.03 - (H_2S\% + CO_2\%)]$$

The ADP is adjusted by multiplying the ADP by the AGF, that is:

The acid gas content of a well event, used by the department for the determination of the AGF, will be according to the records of the ERCB.

A depth factor (DF) is required for all well events, and is calculated based on the measured depth (MD) according to the records of the ERCB for that well event. Information on the MD, of a well event, can be found on the Petroleum Registry of Alberta (PRA) in the 'Infrastructure' section.

The DF is used in the determination of the quantity component (r_q) of the royalty rate; it adjusts the quantity component royalty formula for measured depths that exceed 2000 metres. The DF for a well event is determined based on the following formula:

$$DF = \left(\frac{MD}{2000}\right)^2$$

A well event with a MD greater than 2,000 metres will receive a royalty adjustment based on production from the well event. A well event without a reported MD or with MD less than or equal to 2,000 metres will have a DF of 1.00. The DF is capped at 4.00 for well events with MD greater than or equal to 4,000 metres.

If the MD is

- ≤ 2,000 metres, then the DF=1.00
- >2,000 metres and <4,000 metres, then DF= $\left(\frac{MD}{2000}\right)^2$
- ≥4,000 metres, then the DF=4.00